PUBLIC (REDACTED) VERSION

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	)))))))))	**REBUTTAL TESTIMONY OF MATTHEW KALEMBA ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew Kalemba and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Distributed Energy Technologies Planning & Forecasting for Duke Energy.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring the following rebuttal exhibits, which are described below:

- Kalemba Rebuttal Exhibit 1: Renewable Cross Reference Table
- Kalemba Rebuttal Exhibit 2: CCEBA's[1] Response to DEC/DEP Request for Production 1-14.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared by me or at my direction and under my supervision.

[1] On June 26, 2019, the Commission issued Order Nos. 2019-467 and 2019-468 granting the South Carolina Solar Business Alliance, Inc.'s ("SCSBA") petition for intervention in these proceedings. On March 10, 2021, the Commission issued Order No. 2021-167 granting SCSBA's Motion to substitute CCEBA as the party of record and participant in these Dockets.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony addresses the testimony of ORS Witness Anthony Sandonato, Carolinas Clean Energy Business Association ("CCEBA") Witness Kevin Lucas, and CCEBA Witness Arne Olsen as they relate to the Companies' cost and operational assumptions for solar and battery storage. I also address how the Companies' applied the results from the 2018 Solar Capacity Value Study and 2020 Storage Effective Load Carrying Capability Study ("Storage ELCC Study"), which were conducted by Astrapé Consulting, LLC ("Astrapé") for the Companies.

Section II of my testimony provides a summary of the various solar penetrations shown in the Companies' IRPs, in both the six portfolios and in certain sensitivities. Section III addresses intervenor comments on the Companies' solar cost assumptions and explains why the Companies' cost assumptions are reasonable and generally comparable to other industry standards. Similarly, Section IV addresses intervenor comments on the Companies' battery storage cost assumptions and defends the methodology the Companies used to develop those costs. A critical issue raised in these two sections regarding cost projections is the scrutiny and care that should be applied in attempting to compare utility-specific cost projections developed for long-term resource planning against generic industry benchmarks. As my testimony explains, while industry reports and benchmarks, such as NREL's Annual Technology Baseline, can be helpful in considering cost trends, they are not a substitute for utility-specific cost projections.

Section V of my rebuttal testimony discusses the 2018 Solar Capacity Value Study and its relationship to the IRP and the winter capacity value of solar. Section V also addresses operational assumptions for solar, including the interconnection limitations and "fixed tilt" versus "tracking" solar configurations. Finally, Section VI addresses the Storage ELCC Study and the manner in which the Companies' applied the results of the study to the IRPs.

II: OVERVIEW OF SOLAR IN IRPs

Q. WITNESS LUCAS[2] AND WITNESS OLSON CRITICIZE THE COMPANIES' SOLAR COST AND OPERATIONAL ASSUMPTIONS AS OVERINFLATING THE COST AND VALUE OF SOLAR IN THE COMPANIES IRPs. BEFORE RESPONDING TO THESE SPECIFIC CRITICISMS, PLEASE PROVIDE THE COMMISSION AN OVERVIEW OF THE AMOUNT OF SOLAR CONNECTED IN THE VARIOUS PORTFOLIOS AND SENSITIVITIES PRESENTED IN THE IRPs.

A. The IRPs present six portfolios and a number of sensitivities that provided a view of solar additions across a range of potential futures including varying carbon costs, solar prices, and interconnection constraints. Figure 1 below summarizes the total amount of DEP and DEC nameplate solar in each portfolio by the end of the planning horizon in 2035. As shown in Figure 1, the solar additions called for across the various portfolios are significant.

[2] CCEBA Lucas Direct, at 32-47; CCEBA Olson Direct, at 7-13.

Kalemba Rebuttal Figure 1:
Total Nameplate Solar (in MW) In DEC and DEP at Year End 2035 in Each Portfolio

	Base without Carbon Policy (A)	Base with Carbon Policy (B)	Earliest Practicable (C)	70% CO2 Reduction: Wind (D)	70% CO2 Reduction: SMR (E)	No New Gas Generation (F)
2035 Nameplate Solar	8,650	12,325	12,400	16,243	16,243	16,393

Figure 2 below summarizes the total amount of nameplate solar in some of the key sensitivities performed in the Base with Carbon Policy portfolio

Kalemba Rebuttal Figure 2:
Total Nameplate Solar (in MW) In DEC and DEP at Year End 2035 in Sensitivity Analysis

	Base with Carbon Policy (B)	Low Solar Cost Sensitivity	High Solar Cost Sensitivity	High Renewable Penetration Sensitivity	Low Fuel Cost Sensitivity	High Fuel Cost Sensitivity
2035 Nameplate Solar	12,325	12,775	9,700	14,893	11,800	12,550

Q. WHY IS IT IMPORTANT TO EVALUATE SENSITIVITIES IN THE IRP?

A. As a threshold matter, Act 62 requires a variety of sensitivities to be performed including some of the sensitivities presented in Figure 2. Additionally, these sensitivities can help Commissioners, policy makers, customers, intervenors, and the Companies see the impact of a wide range of variables, in addition to those evaluated in the six portfolios. Such sensitivity analysis can also illustrate the impact of certain changes requested by CCEBA's witnesses in this proceeding, such as reducing the cost of solar or changing the interconnection limit. These sensitivities also highlight which variables have a larger or smaller impact on the amount of renewables selected in each portfolio. For instance, decreases in solar prices or changes in fuel prices have a relatively small impact on the amount of renewables in the plan, but increases in solar prices can reduce the amount of selected solar by over 20%.

Q. THE ORS RECOMMENDED THAT THE COMPANIES PROVIDE A TABLE IDENTIFYING EACH RENEWABLE RESOURCE OPTION THAT WAS MODELED, AND INCLUDE WHETHER THE RESOURCE WAS FORCED-IN OR ECONOMICALLY SELECTED, AS WELL AS, SEVERAL OTHER SUGGESTIONS FOR HELPING TO IDENTIFY WHAT THE SOURCE OF RENEWABLE RESOURCES THAT WERE IN THE IRPs.[3] WERE YOU ABLE TO DEVELOP THIS INFORMATION?

A. Yes, this information is provided in my Exhibit 1. This exhibit includes the annual amount of solar added by category or program; whether the solar is "designated," "mandated," or "undesignated;" a cross-reference to the appropriate row number in the DEC or DEP LCR tables which are identified as Table 12-F in the filed 2020 DEC and DEP IRPs; and the solar profiles modeled in the system production cost model, PROSYM.

III: SOLAR COST ASSUMPTIONS

Q. PLEASE SUMMARIZE INTERVENORS COMMENTS ON THE COMPANIES' UTILITY SCALE SOLAR CAPITAL COSTS.

A. No intervenors challenge the Companies' utility scale solar capital costs. SBA Witness Lucas states that the Companies' "capital cost assumptions for solar are reasonable."[4] The

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[3] ORS Hayet Direct, at 8.
[4] CCEBA Lucas Direct, at 31.

ORS Report states that "DEC's capital cost assumptions could hardly be considered out of line."[5]

Q. WITNESS LUCAS DISCUSSES THE EXTENSION OF THE FEDERAL INVESTMENT TAX CREDIT ("ITC") THAT OCCURRED IN DECEMBER 2020 AND RECOMMENDS THAT THE COMPANIES UPDATE THEIR CAPITAL COSTS TO REFLECT THIS RECENT CHANGE IN POLICY.[6] DO YOU THINK THIS IS REASONABLE?

A. The Companies will update the modeling of their capital costs to account for this change going forward, but it would not be reasonable to issue an entirely new IRP to incorporate this change in policy. The IRP process is intended to present information that is accurate at a specific point in time when such inputs and assumptions were developed.[7] The 2020 IRPs are based on inputs and assumptions generally fixed in late spring and summer months of 2020 leading up to the September submittal of the IRP. By functional necessity, the inputs and assumptions represent information that was available at that point in time prior to the time of filing. It is inevitable that new information will be available or factual bases for decisions will change after the IRP is finalized. As explained by DEC/DEP Witness Snider, resource planning assumptions are changing constantly, and as such, the Companies' IRPs should be viewed as a dynamic document. It would be impossible to revise the IRP upon each policy change or new information that is released after the IRP is completed. IRP development is a nearly continuous process, and as statutory, regulatory

[5] ORS Report (DEC), at 76; ORS Report (DEP), at 75.
[6] CCEBA Lucas Direct, at 32-35.
[7] Witness Lucas admits that the information specific to the ITC was accurate at the time the Companies finalized the IRP. CCEBA Lucas Direct, at 35.

and policy developments continue to occur, these new developments will inform future IRPs.

Q. WHEN WILL THE COMPANIES INCORPORATE THE EXTENSION OF THE ITC INTO THEIR IRP ASSUMPTIONS?

A. The extension to the ITC is being incorporated into the assumptions used in the IRP Update, which will be filed with the Commission in less than six months. If the Companies were to incorporate this change in policy into a modified IRP, a Commission order on a modified IRP in these dockets would not be expected until December 2021/January 2022. This timing makes a modified IRP incorporating these changes obsolete in light of the September 2021 IRP Update, which will be available before the 2020 IRPs are ever approved.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN SOLAR CAPITAL COSTS AND SOLAR FIXED O&M COSTS?

A. In general, solar capital costs represent the materials, engineering, and labor required to construct a facility and interconnect that facility to the electrical grid. Fixed O&M costs represent the annual fixed costs to operate and maintain the solar facility over its lifetime and includes items such as labor, land lease costs, and replacement costs for components over the life of the solar facility. Land lease and labor costs generally represent a larger percentage of the facility's fixed O&M costs than any other category of costs.

Q. ON PAGE 36 OF WITNESS LUCAS' TESTIMONY HE STATES THAT THE COMPANIES' SOLAR PV CAPITAL FORECAST "REFLECTS CAROLINA-SPECIFIC FACTORS SUCH AS LABOR COSTS AND LAND RENTAL WHILE CAPTURING THE NATIONAL-LEVEL LONGER-TERM COST REDUCTION TRENDS AS SOLAR TECHNOLOGY EVOLVES." IS WITNESS LUCAS'S DESCRIPTION CORRECT?

A. It is partially correct. The Companies' capital cost forecast includes some labor costs, but land lease costs are included in the Companies' fixed O&M cost forecasts. Labor and land costs are based on Carolinas-specific land costs.

Q. WITNESS LUCAS'S TESTIMONY AND RECOMMENDATIONS REGARDING SOLAR AND STORAGE COST ASSUMPTIONS RELY HEAVILY ON WHAT HE DESCRIBES AS "NREL ATB CASES." CAN YOU EXPLAIN TO THE COMMISSION WHAT THIS IS?

A. The NREL Annual Technology Baseline, or "ATB," was developed by NREL for their own energy analysis to "document transparent, normalized technology cost and technology assumptions; document potential pathways for impacts of R&D on renewable energy technologies; enable consistency in technology assumptions across analysis projects; facilitate the tracking and sourcing of input assumptions, and reduce the lead time when conducting scenario analysis."[8] The ATB presents Conservative, Moderate, and Advanced (or high, mid, and low) cost projections for most renewable technologies and battery storage. For battery storage cost projections, the NREL ATB relies on the results of NREL's "Cost Projections for Utility-Scale Battery Storage: 2020 Update" (referred to

[8] NREL "About the 2020 ATB," *available at* https://atb.nrel.gov/electricity/2020/about.php.

herein as "NREL's 2020 Battery Report") which details NREL's assumptions for developing long-term battery storage cost projections used in the ATB.[9]

Q. WHAT PURPOSE DO YOU BELIEVE THE NREL ATB INFORMATION SHOULD PROVIDE IN REGULATORY PROCEEDINGS SUCH AS THIS?

A. The NREL ATB cases provide helpful information in assessing industry trends and gathering generalized industry information. However, in long-term resource planning, it is not appropriate to utilize such industry cost projections as "absolute" costs that accurately reflect of the costs expected by any one particular utility. As I explain through my rebuttal testimony, this is particularly true in the case of battery storage where the technology is evolving rapidly.

Q. WITNESS LUCAS RECOMMENDS THAT THE COMPANIES SHOULD APPLY A 19% DISCOUNT TO ITS SOLAR FIXED O&M COSTS.[10] DOES WITNESS LUCAS OFFER ANY JUSTIFICATION FOR WHY A 19% COST REDUCTION IS REASONABLE?

A. No, Witness Lucas does not offer any meaningful justification for this. While it is true that the Companies' solar capital cost projections are approximately 20% less than the NREL ATB Moderate case, this fact is only coincidental. The Companies did not develop their capital costs to be intentionally 20% less than NREL ATB Moderate case. To the contrary, the Companies' solar costs are specifically developed to represent the cost to construct and operate a solar facility in the Carolinas. To apply a 20% reduction to the NREL ATB fixed

[9] Cole, Wesley, & Frazier, Will A., *Cost Projections for Utility-Scale Battery Storage: 2020 Update.* (No. NREL/TP-6A20-75385), National Renewable Energy Laboratory (2020), *available at* https://www.nrel.gov/docs/fy20osti/75385.pdf ("NREL Battery Storage 2020 Update")
[10] CCEBA Lucas Direct, at 39.

O&M costs, as recommended by Witness Lucas, merely because the Companies' solar capital costs were 20% below NREL would result in fixed O&M costs that are not representative of forecasted fixed O&M costs in the Carolinas.

Q. THE ORS STATES THAT THE COMPANIES' SOLAR LCOE COST APPEARS TO BE HIGH RELATIVE TO OTHER ESTIMATES.[11] ORS PROVIDES THIS COMPARISON IN TABLE 14.[12] DO YOU BELIEVE THE INFORMATION IN TABLE 14 PROVIDES A FAIR COMPARISON OF COSTS?

A. I do not. Based on my review of the data in Table 14 and my review of ORS responses to discovery requests, the LCOE values shown are not easily comparable.[13] For instance, I believe the ORS presents the Companies' LCOE on a nominal basis, but the NREL ATB LCOE is presented on a real basis. The $/MWh difference between a nominal LCOE and a real LCOE can be significant, so it is important to make sure the comparison is on a similar basis.

Beyond the potential inconsistency between the real and nominal LCOE values, the capital cost and fixed O&M assumptions from Lazard appear to be outliers in the data provide in Table 14.[14] Based on my professional judgment, the capital cost to achieve a 34% capacity factor for standalone solar in the Carolinas would likely be much higher than the published number in the Lazard study. The Lazard cost may be possible in regions such as the southwestern United States, but I believe that achieving 34% capacity factor with today's technologies is not possible in the Carolinas for that stated cost.

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[11] ORS Report (DEC), at 76; ORS Report (DEP), at 75.
[12] ORS Report (DEC), at 73-74; ORS Report (DEP), at 74-75.
[13] The Companies intend to request additional information through discovery to understand this comparison more fully.
[14] ORS Report (DEC), at 73-74; ORS Report (DEP), at 74-75.

Q. EARLIER IN YOUR TESTIMONY, YOU MENTIONED THE SENSITIVITY ANALYSIS THE COMPANIES CONDUCT AS PART OF DEVELOPING THE IRPs. DID THE COMPANIES CONDUCT SENSITIVITY ANALYSIS THAT MODELED SOLAR AT DIFFERENT PRICES?

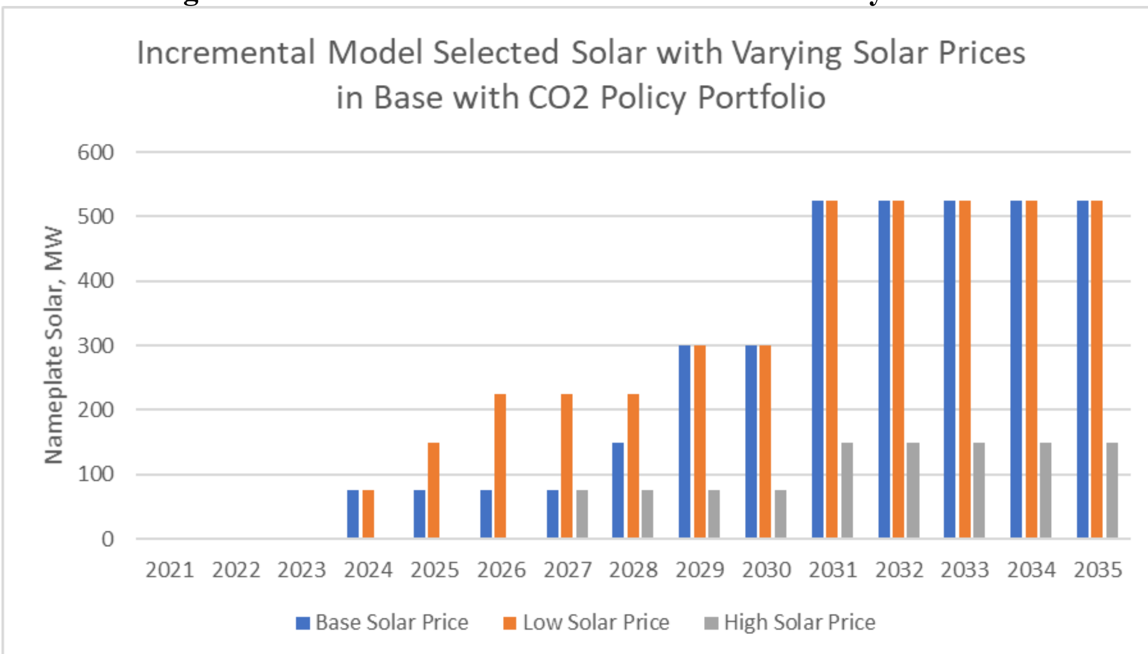
A. Yes. Consistent with Act 62, the Companies performed low and high solar cost sensitivities that are useful for identifying the impacts to the resource plans if solar costs varied from the base assumptions. The percentage adjustment from the base solar costs are represented below in Figure 3.

Kalemba Rebuttal Figure 3: Solar Cost Sensitivity Assumptions

% $/W-AC Difference from Base	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
High Solar Cost Sensitivity	0%	5%	9%	13%	17%	20%	24%	27%	31%	34%
Low Solar Cost Sensitivity	0%	-9%	-11%	-15%	-18%	-20%	-22%	-23%	-23%	-24%

As shown in Figure 4 below, under the low solar cost sensitivity, the model selects an additional 450 MW of solar in DEC and DEP combined between 2025 and 2028. As a result, decreasing the Companies' solar cost assumptions (which are already comparable to or less than NREL's ATB solar projections, as shown in Lucas Figure 4 and Lucas Figure 5) will have limited impact on the amount of solar selected in the 2020 IRP.

Kalemba Rebuttal Figure 4: Incremental Model Selected Solar Under Base, Low, and High Solar Price Sensitivities in Base with CO2 Policy Portfolio



IV: <u>BATTERY STORAGE COST ASSUMPTIONS</u>

Q. WITNESS LUCAS CLAIMS THAT THE COMPANIES' BATTERY STORAGE COST ASSUMPTIONS ARE INFLATED, AS COMPARED TO OTHER SOURCES THAT HE PROVIDES IN TABLE 4.[15] DO YOU BELIEVE THAT WITNESS LUCAS'S TABLE 4 PROVIDES A MEANINGFUL COMPARISON OF THE COMPANIES' BATTERY STORAGE PRICES COMPARED TO OTHER INDUSTRY SOURCES?

A. No, I do not. Witness Lucas has "cherry-picked" specific industry sources that appear to demonstrate that the Companies' storage costs are higher than all other industry sources. With a further analysis into NREL's ATB's cost projection, and reviewing additional industry sources, it is clear that this is not the case.

[15] CCEBA Lucas Direct, at 40.

First, I will address the NREL ATB cost estimates because Witness Lucas's testimony focuses on these primarily. NREL's 2020 Battery Report Figure 4 [16] which is included as Figure 5 below, shows the variety of starting points for battery storage costs from industry sources that NREL considered in developing the NREL ATB cost estimates, represented in 2019 $/kWh costs. I have added the solid blue line to represent the Companies' 2020 IRP battery cost starting point, but increased to a 2019 starting point consistent with NREL's methodology.[17]

[BEGIN CONFIDENTIAL]

Kalemba Confidential Rebuttal Figure 5: Comparison of DEC/DEP 2020 IRP Battery Costs to Published Resources Using NREL Methodology

[redacted]

Figure 4. Current battery storage costs from studies published in 2018 or later. The NREL value (Feldman et al. Forthcoming) was selected as the 2019 starting cost for this work.

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[16] NREL Battery Storage 2020 Update at 8.

[17] The NREL Battery Storage 2020 Update states that "If a publication began its projections after 2019, the 2019 value was estimated using linear extrapolation from the nearest value. For example, if the 2020 price was $500/kWh and the 2021 price was $480/kWh, then the 2019 price was assumed to be $520/kWh." Similarly, to come up with a comparable number, the Companies linearly extrapolated the represented 2019 battery cost using the 2020 IRP assumptions for battery costs in 2020 and 2021.

[END CONFIDENTIAL]

The green triangle in the figure represents NREL's starting point for its cost projections. As shown in the figure, the Companies' starting point for battery storage costs is within the range of published resources such as WoodMackenzie and NIPSCO and at the very top end of the EPRI range.

Q. IN YOUR FIGURE 5, NREL'S STARTING COSTS STILL APPEAR TO BE SOMEWHAT LOWER THAN THE COMPANIES' STARTING COSTS. CAN YOU EXPLAIN WHY THIS IS?

A. NREL developed its starting point battery cost and "asse[d] the quality of [their] starting point,"[18] by comparing their costs to published resources as shown above. As utilities look for opportunities to maximize the benefits of batteries, costs are becoming more use-case specific, and it is becoming increasingly difficult to rely on published resources to justify battery costs for long-term planning purposes. The NREL 2020 Battery Report highlights this very point, stating:

> There are a number of challenges inherent in developing cost and performance projections based on published values. First among those is that the definition of the published values is not always clear. For example, dollar year, duration, depth-of-discharge, lifetime, and O&M are not always defined in the same way (or even defined at all) for a given set of values. As such, some of the values presented here required interpretation from the sources specified. Second, many of the published values compare their published projection against projections produced by others, and it is unclear how much the projections rely upon one-another. Thus, if one projection is used to inform another, that projection might artificially bias our results (toward that particular projection) more than others. Third, because of the relatively limited dataset for actual battery systems and the rapidly changing costs, it is not clear how different battery projections should be weighted. with something here.[19]

[18] NREL 2020 Battery Storage 2020 Update, at 7.
[19] *Id.* at 2.

This helpful explanation emphasizes precisely why one cannot simply compare the Companies' battery storage costs to the NREL ATB or any other generic industry publication and accurately conclude that the Companies' battery costs are high.

It is important to understand that the battery the Companies include in the IRP is designed to meet both the current and potential operating requirements that may be placed on battery storage. For this reason, the battery is designed to be flexible, reliable and safe to operate. It is likely that at least some of the published battery costs meet the Companies' requirements, however it is likely that many of the published battery costs would not be robust enough to meet the needs of the Companies' system and some may not even meet the basic requirements to interconnect to the system. Furthermore, some published resources may not properly include the cost impacts of Depth of Discharge (DoD) limitations that are required of some battery technologies to meet manufacturer warranty requirements. This point is further emphasized in the NREL 2020 Battery Report, which states that the chart "demonstrate[s] that there is considerable uncertainty (+/- $100/kWh) in the current price of battery storage systems."[20]

Q. CAN YOU EXPLAIN FURTHER HOW THE COMPANIES' BATTERY DESIGN ASSUMPTIONS IMPACT THE BATTERY COSTS?

A. Yes. The third-party model that the Companies use to inform its battery cost assumptions allows the user to adjust design requirements and develop cost projections based on those new design assumptions. Confidential Figure 6 below shows the impact of making the following adjustments to the design of the battery:

[20] *Id.* at 7.

- Moving from controls that require real time optimization to controls that are based on pre-programmed commands.
- Moving from high quality HVAC and fire suppressions systems including back up power sourced from reputable vendors to standard systems that just meet the minimum necessary codes and standards.
- Moving from greenfield siting requiring new transmission or distribution interconnections to a brownfield site that does not require any interconnection.
- Removing costs associated with a DoD requirement.

[BEGIN CONFIDENTIAL]

Kalemba Confidential Rebuttal Figure 6: Redesigned DEC/DEP Battery Illustration

[redacted]

[END CONFIDENTIAL]

As shown by the blue dashed line in Confidential Figure 7 below, if these adjustments were made to the design of the battery, it would align much closer to the starting cost of the NREL battery.

[BEGIN CONFIDENTIAL]

Kalemba Confidential Rebuttal Figure 7: Comparison of DEC/DEP 2020 IRP Battery Costs, "Redesigned DEC/DEP Battery Costs," and Published Resources Using NREL Methodology

[redacted]

Figure 4. Current battery storage costs from studies published in 2018 or later. The NREL value (Feldman et al. Forthcoming) was selected as the 2019 starting cost for this work.

[END CONFIDENTIAL]

Q. WITNESS LUCAS CLAIMS THAT YOUR STATEMENT THAT OTHER BENCHMARKS "LIKELY ONLY CALCULATE THE COST OF THE BATTERY BASED ON THE RATED ENERGY OF THE BATTERY" RATHER THAN ADJUSTING FOR DOD AND DEGRADATION IS NOT ACCURATE.[21] IS HE CORRECT?

A. No, although Witness Lucas correctly points out that NREL does normalize the published storage costs. However, NREL only normalizes those costs "to develop cost *projections*"

[21] CCEBA Lucas Direct, at 40-41.

as noted on page 2 of the NREL report, but as I discussed previously, NREL does not normalize costs for the starting point of those cost projections.

Q. SETTING ASIDE THE COMPARISON TO NREL'S STARTING POINT ASSUMPTION FOR BATTERY STORAGE COSTS, HOW DO THE COMPANIES' COST DECLINES FOR BATTERY STORAGE OVER THE PLANNING HORIZON COMPARE TO THOSE IN THE NREL ATB?

A. The Companies' cost declines are very similar to the NREL ATB Advanced case. From 2020 to 2029, the Companies' battery costs decline 34% while the ATB Advanced case declines 37%. The Companies' battery cost decline exceeds the NREL ATB Moderate case which only declines 27%.

Q. CAN YOU BRIEFLY EXPLAIN WHAT THE NREL ATB ADVANCED, MODERATE, AND CONSERVATIVE CASES REPRESENT?

A. For battery storage, these terms are based on the low (Advanced), mid (Moderate), and high (Conservative) projections from NREL's 2020 Battery Report. The low, mid, and high projections are "the minimum, median, and maximum point respectively in 2020, 2025, and 2030" of NREL's normalized cost projections.[22] As shown in Figure 8 below, which is Figure ES-1 in NREL's 2020 Battery Report, the mid or Moderate projections align with the median projections of the publications evaluated by NREL, while the low or Advanced projections track the most aggressive cost declines in those publications. Significantly, the Companies' cost projections are very well aligned with NREL's most aggressive cost projections through 2035.

[22] NREL 2020 Battery Storage 2020 Update, at 7.

Kalemba Rebuttal Figure 8: Figure ES-1 from NREL's 2020 Battery Report Showing High, Mid, Low Battery Normalized Battery Costs Compared to Normalized Published Values and DEC/DEP's Normalized 2020 IRP Values

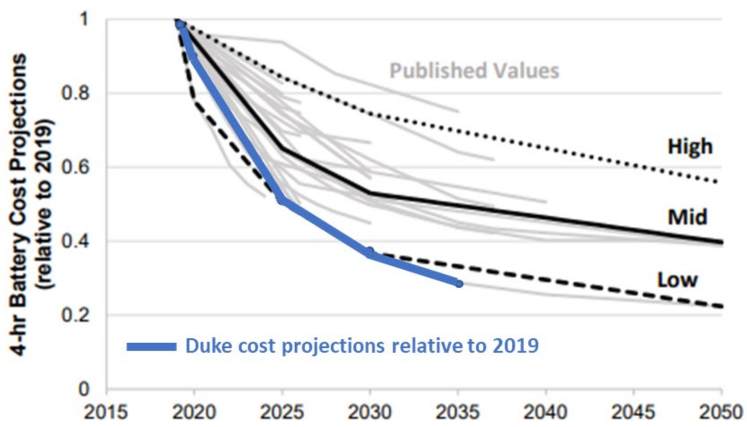


Figure ES-1. Battery cost projections for 4-hour lithium-ion systems, with values relative to 2019.
The high, mid, and low cost projections developed in this work are shown as the bolded lines.

Q. REGARDLESS OF THE COMPANIES' ESTIMATED BATTERY COSTS, IS IT APPROPRIATE TO USE NREL'S LOW COST PROJECTIONS FOR IRP PLANNING PURPOSES?

A. Generally, for long-term planning purposes, in the absence of utility specific data, the Companies would tend to use median forecasts. However, as I mentioned above, the Companies' projections for cost declines of battery costs over the next decade align well with the NREL Low cost curve. The point of contention arises with the starting point which, in the case of battery storage costs in the 2020 IRP, is based on a battery energy storage system designed to meet the needs of the DEC and DEP systems.

Q. WITNESS LUCAS'S TABLE 4 PROVIDES CAPITAL COSTS FROM A SANTEE COOPER REQUEST FOR INFORMATION ("RFI") AS A COMPARISON TO THE COMPANIES' COSTS.[23] DO YOU THINK THIS IS A REASONABLE COMPARISON TO MAKE?

A. No, I do not believe it is. First, Witness Lucas provides no information supporting how these costs were derived. The Companies requested this information from Witness Lucas through discovery, but his response merely pointed to the DESC Order, which provides no additional detail.[24] After spending time investigating any documents that support the information contained in Witness Lucas's testimony, the Companies located the "Initial Assessment of RFI Submittals" that was produced by NFront Consulting on November 20, 2019.[25] From the outset, it is important to understand that generally a Request for Information, or RFI, is merely a request for non-binding indicative pricing from the industry. Moreover, to my knowledge, Santee Cooper has not executed any contracts that reflect the price shown in Witness Lucas's testimony. Additionally, the Santee Cooper RFI actually requested pricing for both standalone solar and solar plus storage facilities, but not standalone energy storage, a critical distinction that is omitted by Witness Lucas. This distinction is important because the pricing associated with storage paired with solar can be lower than standalone storage as there are some synergies between the storage facility and the solar asset.

Finally, a review of the overall prices submitted by developers in response to this

[23] CCEBA Lucas Direct, at 40.
[24] *See* Kalemba Rebuttal Exhibit 2.
[25] nFront Consulting LLC Initial Assessment of RFI Submittals (Nov. 20, 2019), *available at* https://admin.sc.gov/sites/default/files/Exhibit%20A%20-%20Santee%20Cooper%20Reform%20Plan.PDF.

RFI raises questions as to the credibility of the information overall. The average levelized price of the proposals in the RFI was $27.90/MWh for 854 MW. Requests for bids into this RFI began October 2019. This is only 3 months after the Companies released the CPRE Tranche 2 RFP in which 589 MW were identified as finalists at an average price $36.74/MWh in DEC. The difference in prices between the two is significant, and without being able to review the bids of the Santee Cooper RFI, I believe such a significant price disparity calls into question the usefulness of the Santee Cooper RFI responses as an industry benchmark at all. For all of these reasons, the Santee Cooper RFI pricing should be disregarded as a benchmark for pricing relevant to the Companies' projected standalone storage costs for IRP purposes.

Q. WITNESS LUCAS'S SPECIFIC RECOMMENDATION TO THE COMMISSION IS FOR THE COMPANIES TO USE NREL ATB ADVANCED SCENARIO FOR ITS STORAGE COSTS. DO YOU BELIEVE THIS IS APPROPRIATE?

A. No, as I described previously, the NREL ATB can inform the reasonableness of the Companies' battery cost trends, but I do not believe it is appropriate to apply the NREL ATB costs directly in the manner advocated for by Witness Lucas. The Companies' capital cost assumptions accurately reflect the cost to build and install the type of battery storage system that will reliably and safely meet the needs of the Companies' customers. As such, I believe the Companies' assumptions of battery capital costs are reasonable for use in the Companies' 2020 IRPs.

Q. MOVING TO COSTS FOR STORAGE COUPLED WITH SOLAR, WITNESS LUCAS TAKES ISSUE WITH THE COMPANIES' APPROACH TO DEVELOPING COSTS FOR SOLAR PLUS STORAGE BECAUSE IT IS DIFFERENT THAN HOW COSTS ARE DEVELOPED FOR STANDALONE STORAGE.[26] IS IT APPROPRIATE TO HAVE TWO DIFFERENT METHODOLOGIES FOR THESE TECHNOLOGIES?

A. Yes, in this instance it is appropriate. In the IRP, the Companies assume solar assets have 30-year lives, while battery storage assets have 15 year lives. Over the life of a battery, the energy capacity of the battery cells degrade, and if nothing is done to account for that degradation, the battery will hold significantly less usable energy at year 15 than it did during year one. For standalone storage, the Companies account for degradation by "augmenting" the battery with additional battery cells at regular intervals to maintain the usable energy of the battery.

The alternative approach is to "overbuild" the battery so that as the battery cells degrade, the amount of usable energy in year 15 is the same as in year one. Because the life of a storage asset does not align with the life of the solar asset it is paired with, at some point during the life of the solar asset, certain components of the battery system, including the battery cells, must be replaced. While it may be appropriate to augment a battery over the 15-year life, there is risk that as battery technologies rapidly evolve, the ability to cost-effectively and reliably augment the battery may be challenged due to factors such as supply chain risk for equipment obsolescence, difficulty balancing the system state of health, and cell integration challenges. These risks would only increase if augmentation

[26] CCEBA Lucas Direct, at 42-45.

were assumed for maintaining a battery's energy capacity over a 30-year period. For this reason, the Companies elected to model the storage plus solar asset by initially overbuilding the battery at year one to achieve a 15-year operation, then replacing the battery cells and other battery components that are likely to be at or near end of life with another overbuilt battery to achieve another 15-years of operation.

Q. WITNESS LUCAS CLAIMS THAT THE COMPANIES' ASSUMPTION THAT 100% OF THE BATTERY PACK MUST BE REPLACED MIDWAY THROUGH THE 30-YEAR LIFE IS "ERRONEOUS."[27] DO YOU AGREE WITH THIS ASSESSMENT?

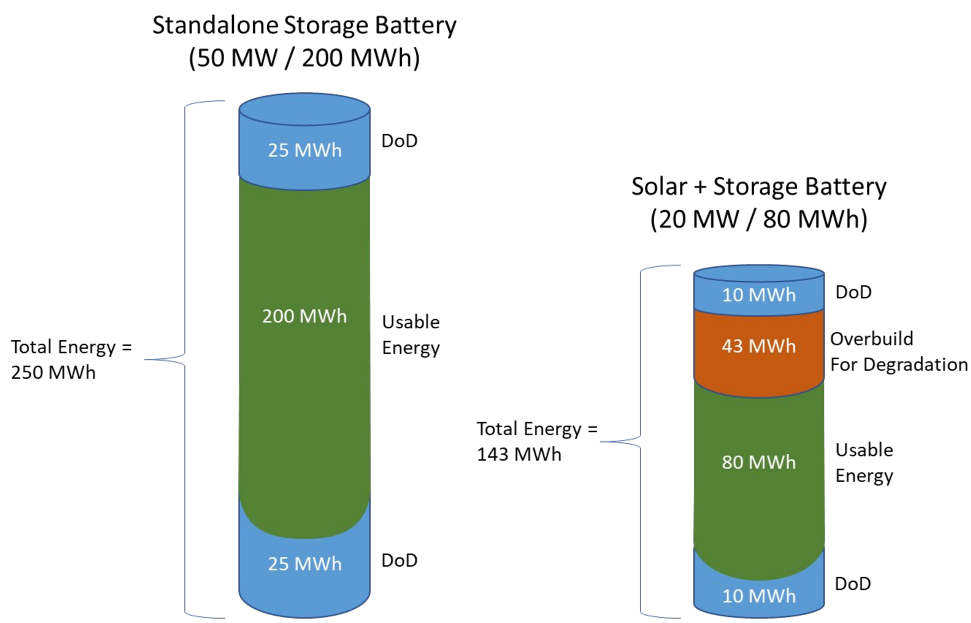
A. No, I do not. Battery technology is still maturing relative to traditional grid infrastructure, and I am not aware of any sufficiently reliable data that validates precisely how a utility scale battery energy storage system that is designed to match the life of a 30-year solar asset will operate when the battery is 15-years into its life cycle. But it is common for lithium-ion battery cells to require replacement after 10 to 15 years of operation depending on several factors including cycles per day, temperature conditions, and available energy requirements. The Companies' assumption that the battery pack must be replaced is a reasonable assumption given the still maturing state of utility scale battery technology.

[27] *Id.* at 43.

Q. WITNESS LUCAS SUGGESTS THAT THE COMPANIES' PROJECTIONS OF BATTERY STORAGE COSTS BETWEEN STANDALONE STORAGE AND SOLAR PLUS STORAGE ARE "INTERNALLY INCONSISTENT."[28] IS THIS TRUE?

A. It is not true. The Companies' projections are fully consistent, and his line of reasoning is the **exact** reason why one cannot simply compare battery costs across publications, or even between battery use cases in an IRP, unless one understands what they are comparing. Before explaining his error, the following simplistic graphic shows the difference between the standalone storage assumption and the solar + storage assumption for the battery asset.

Kalemba Rebuttal Figure 9: Comparison of Standalone Storage and Solar + Storage Batteries in the 2020 IRP



The battery on the left in the figure is the Companies' assumption for standalone storage which is a 50 MW / 200 MWh asset. The battery on the right is the assumption for the storage asset that is paired with solar in a solar plus storage configuration. The standalone

[28] *Id.* at 44-45.

battery is larger and does not include overbuild, while the storage paired with solar does include overbuild.

Witness Lucas attempts to compare the battery pack prices between these two batteries in order to claim the Companies are using different battery pack prices. However, his analysis is flawed because he did not conduct the comparison on an "apples to apples" basis. Figure 10 below summarizes the numbers Witness Lucas presents in his testimony,[29] except he did not calculate the standalone storage Usable Energy + DoD number in his analysis. He simply stopped at the Usable Energy Basis for the standalone storage asset.

[BEGIN CONFIDENTIAL]

Kalemba Confidential Rebuttal Figure 10: Witness Lucas Comparison of DEC/DEP Battery Pack Costs

[redacted]

[END CONFIDENTIAL]

Without knowing anything else about the batteries, the only numbers that are truly comparable in the table are the Usable Energy + DoD number for the Standalone Storage asset and the Usable Energy + DoD + Overbuild number for the Solar + Storage Battery Pack because those numbers represent the battery pack cost based on the "Total Energy" of the battery, and as shown, those numbers are the same across the battery use cases.

[29] CCEBA Lucas Direct, at 44.

However, when comparing battery prices across literature, or between utilities, it is often not clear which cost is being represented. The Companies' represent their numbers on a Usable Energy Basis by dividing the total cost of the battery by the usable energy of the battery. Most publications do the same, but as shown above, that number does not tell the complete story. Witness Lucas's testimony on this issue provides a perfect example of this point when he states,

> Considering that Duke plans to initially install the 143 MWh battery for this [solar plus storage] project, it appears the lowest cost estimate is the most appropriate. However, that begs the question as to why the battery pack cost would be so much lower in this configuration than for a standalone storage project…[30]

In reality, had Witness Lucas actually compared the two batteries on the same basis, then he would have realized that the Companies are in fact using the same battery pack prices across the battery use cases.

Q. HOW DO YOU RESPOND TO THE ORS'S RECOMMENDATION THAT THE COMPANIES SHOULD PROVIDE ADDITIONAL JUSTIFICATION FOR THEIR BATTERY ENERGY STORAGE FIXED O&M COST AND CAPACITY FACTOR ASSUMPTIONS?[31]

A. The Companies have identified a non-material issue with their standalone battery storage fixed O&M assumptions. Upon investigation, the Companies discovered that some aspects of regular fixed O&M unrelated to replenishment, were in fact included in the replenishment fixed O&M, thereby inflating the fixed O&M associated with standalone

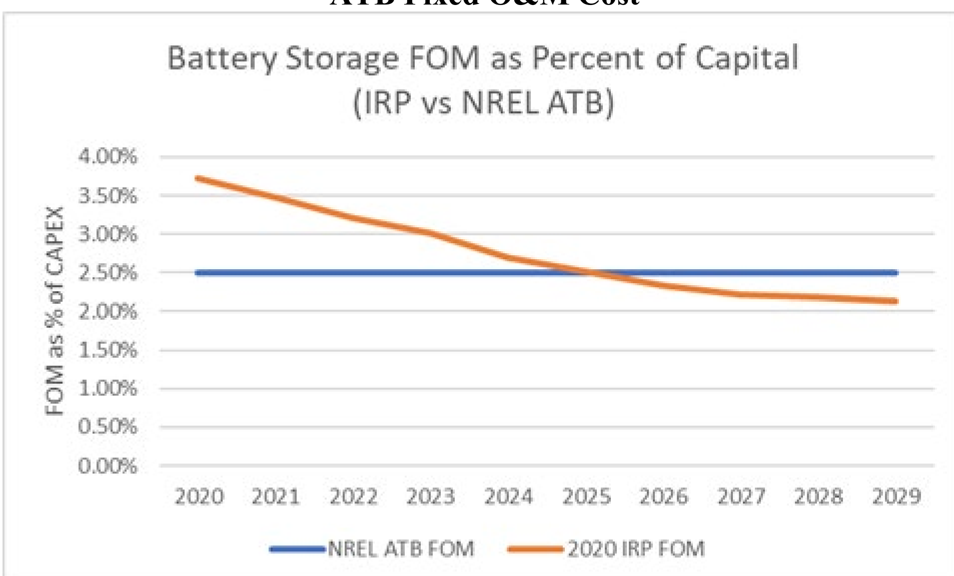
[30] *Id.*
[31] ORS Hayet Direct, at 7.

battery storage. The Companies will correct their fixed O&M assumptions in the upcoming 2021 IRP Update.

Q. DO YOU THINK DISCREPANCY IN THE FIXED O&M COSTS HAS A MATERIAL IMPACT ON THE ANALYSIS CONDUCTED IN THE IRP?

A. No, this discrepancy did not impact the analysis. While the fixed O&M assumptions were high early in the planning period, by 2030, those prices dropped by over 60%. In fact, NREL's assumptions, (across the advanced, moderate, and conservative cases) show that fixed O&M cost ($/kw-year) is 2.5% of the battery capital cost ($/kw). As shown in Figure 11 below, even with this discrepancy, the Companies' fixed O&M assumptions are lower than NREL's assumptions by 2026.

Kalemba Rebuttal Figure 11: Comparison of DEC/DEP IRP Fixed O&M Cost to NREL ATB Fixed O&M Cost

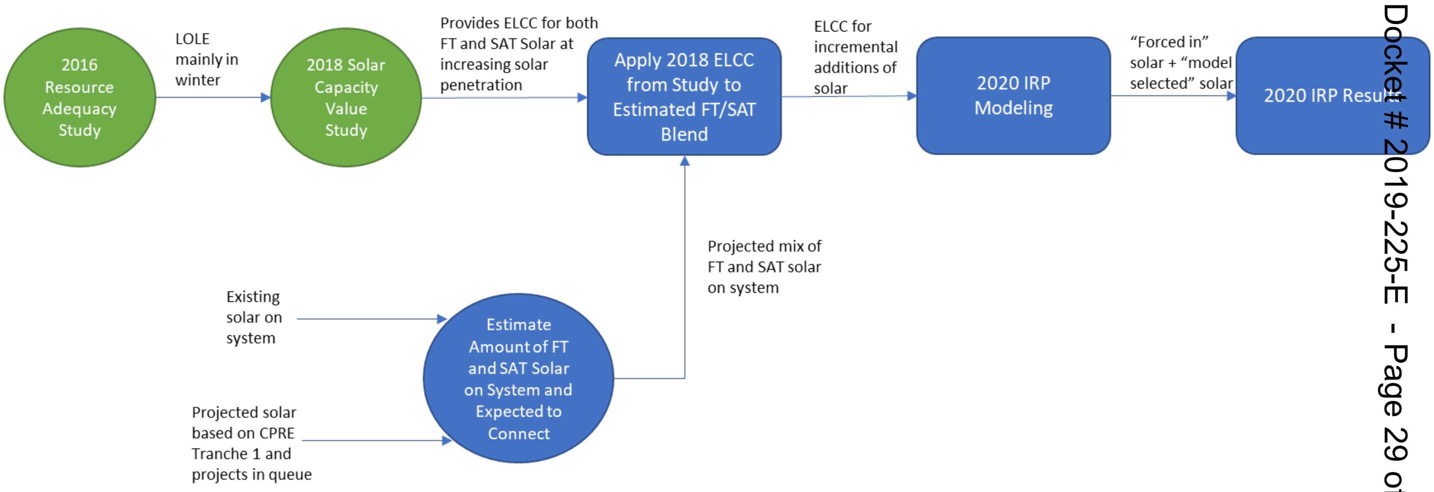


V: SOLAR CAPACITY VALUE STUDY AND SOLAR OPERATIONAL ASSUMPTIONS

Q. ORS RECOMMENDS THAT THE COMPANIES PROVIDE A DETAILED DISCUSSION THAT EXPLAINS HOW THE RESULTS OF THE ASTRAPÉ 2018 SOLAR CAPACITY VALUE STUDY WERE USED TO DERIVE THE ASSUMED WINTER PEAK STANDALONE SOLAR CAPACITY VALUE OF 1 PERCENT. TO BEGIN, CAN YOU PLEASE PROVIDE AN OVERVIEW OF THE PROCESS?

A. Yes. Figure 12 represents a simplified flow diagram of the process for incorporating the results of the 2018 Solar Capacity Value Study into the 2020 IRP.

Kalemba Rebuttal Figure 12: Diagram of Solar Capacity Value Development



In the 2018 IRP, the Companies included the 2018 Solar Capacity Value Study that was based on the results of the 2016 Resource Adequacy Study. Both studies were performed for the Companies by Astrapé using the best information available to the Companies at the time, including load growth, solar penetration on the DEC and DEP systems, expected solar configurations (i.e. fixed tilt or single axis tracking), and other inputs. As explained in

DEC/DEP Witness Wintermantel's testimony, the 2016 Resource Adequacy Study determined that the majority of Loss of Load Expectation ("LOLE") hours were expected to occur in the winter. Astrapé conducted another resource adequacy study in the 2020 IRP which again showed that the majority of LOLE hours occurred in the winter months. Because the 2020 Resource Adequacy Study determined that there was no shift in LOLE hours back to the summer, the Companies determined that applying the results from the 2018 Solar Capacity Value Study in the 2020 IRP was reasonable for planning purposes.

The 2018 Solar Capacity Value Study determined the ELCC for both Fixed Tilt ("FT") Solar and Single Axis Tracking ("SAT") Solar. Those ELCC results were applied to the FT and SAT solar in the 2020 IRP.

Q. WHAT TYPE OF SOLAR RESOURCES DID THE COMPANIES MODEL IN THE 2020 IRPs?

A. The Companies modeled combinations of fixed tilt and single-axis tracking solar facilities. The assumptions were based on projects operating on the Companies' systems at the time inputs to the IRP were being developed, as well as, results from CPRE Tranche 1 which gave insight to the types of facilities developers were designing in the Carolinas.

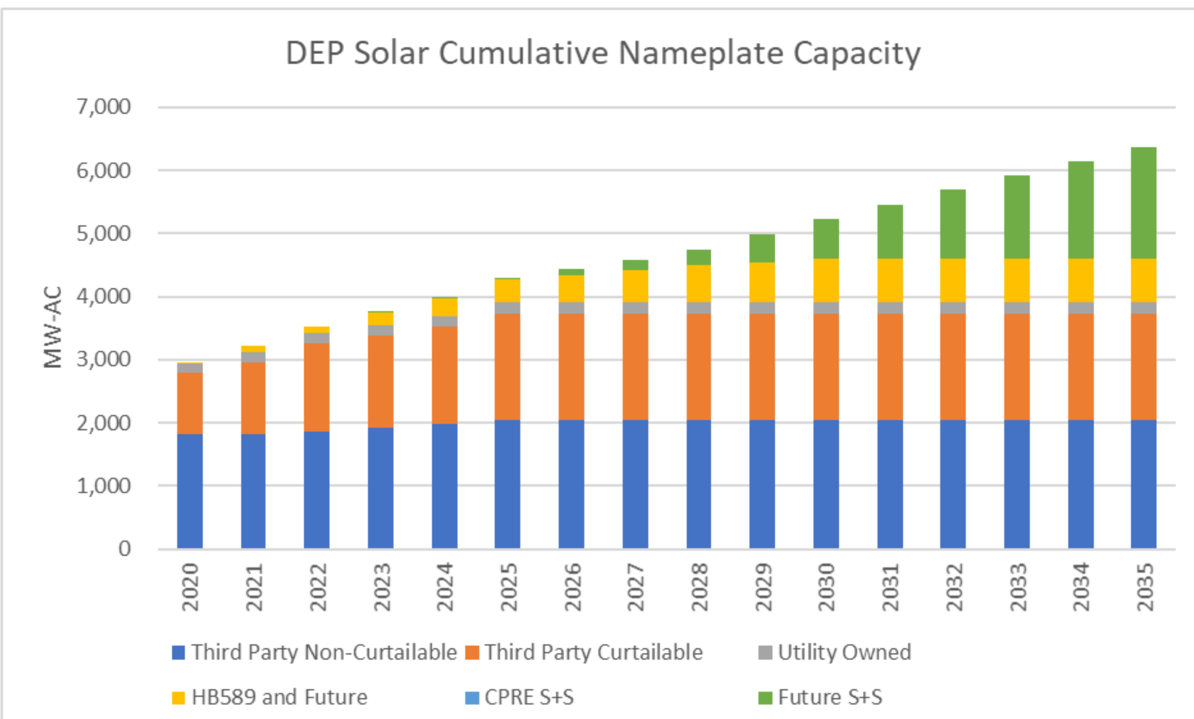
Q. WHAT TYPE OF SOLAR RESOURCES ARE CURRENTLY INSTALLED IN DEC AND DEP, AND WHAT TYPE OF SOLAR RESOURCE OR RESOURCES WERE ASSUMED FOR FUTURE SOLAR?

A. In both DEP and DEC, over 90% of the installed solar MWs, which are primarily PURPA sourced solar assets, are fixed tilt solar facilities. For future standalone solar, whether that is future solar associated with North Carolina HB 589 programs or economically selected solar, the Companies assumed 60% of the MWs would be SAT solar and 40% of the MWs would be fixed tilt solar base on the results of CPRE Tranche 1. As shown in Figure 13 below, the Companies' include six different categories of solar to represent the types of solar that are existing and projected to come on to the system in the future. Figures 13, 14, and 15 below show those types of solar on the DEP and DEC systems at the end of 2020 and projections of the types of solar to be added in the future.

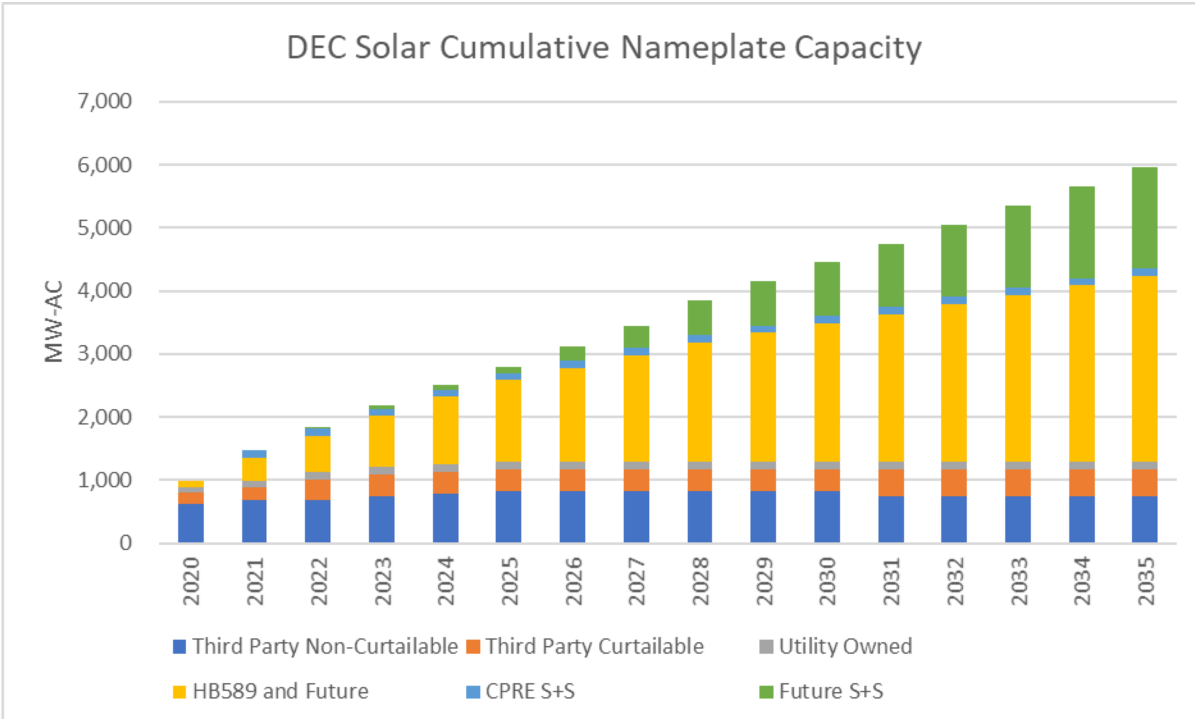
Kalemba Rebuttal Figure 13: Categories of Solar Included in 2020 IRPs

	% Fixed Tilt	% Tracking
Third Party Non-Curtailable	100%	0%
Third Party Curtailable	95%	5%
Utility Owned	92%	8%
HB589 and Future	40%	60%
CPRE S+S	0%	100%
Future S+S	50%	50%

Kalemba Rebuttal Figure 14: Categories of Solar Projected on DEP System in 2020 IRPs



Kalemba Rebuttal Figure 15: Categories of Solar Projected on DEC System in 2020 IRP



Q. WITNESS LUCAS CRITICIZES THE ASSUMPTION THAT ALL PURPA FACILITIES THAT ARE CURRENTLY FIXED-TILT SOLAR WILL BE REPLACED WITH FIXED-TILT SOLAR IN THE FUTURE.[32] WHY WAS THIS A REASONABLE ASSUMPTION?

A. As I stated previously, nearly all of the current PURPA solar facilities that are operational on the Companies' systems today are fixed-tilt, as opposed to tracking. Those existing facilities are not expected to change from fixed-tilt to tracking. The Companies will continue to evaluate the type of solar configurations that PURPA facilities are using and make adjustments to their assumptions based on this information in future IRPs.

[32] CCEBA Lucas Direct, at 54.

Q. WHY IS IT REASONABLE TO ASSUME THAT SOLAR ADDED UNDER CPRE WILL BE 60% FIXED-TILT AND 40% TRACKING?

A. This assumption is based on the information available at the time the IRP was conducted. At that time, the results from CPRE Tranche 1 showed that approximately 60% of final standalone solar projects were SAT projects, while the remaining 40% of projects were fixed tilt. Subsequently, the results of CPRE Tranche 2 became known and 100% of solar projects were designed as single-axis tracking projects. In the 2021 IRP Update, the Companies will reflect 100% SAT for all new solar including Tranche 2 CPRE projects and economically selected solar. Additionally, the Companies are evaluating modeling all future solar + storage projects as 100% tracking.

Q. BASED ON THE ASSUMPTIONS OF THE TYPE OF SOLAR FACILITIES, WHAT DID THE COMPANIES ASSUME FOR CALCULATING THE CONTRIBUTION TO WINTER PEAK CAPACITY FOR SOLAR ON THE SYSTEM?

A. Figure 16 below shows the make-up of incremental additions of standalone solar on the DEP and DEC system across the planning horizon based on the above information.

Kalemba Rebuttal Figure 16: Make up of System and Incremental FT and SAT Solar on DEP and DEC Systems

	DEC				**DEP**			
	System Blend		Incremental Adds		System Blend		Incremental Adds	
	FT	SAT	FT	SAT	FT	SAT	FT	SAT
2020	93%	7%	N/A	N/A	98%	2%	N/A	N/A
2021	83%	17%	56%	44%	97%	3%	79%	21%
2022	78%	22%	61%	39%	96%	4%	95%	5%
2023	75%	25%	57%	43%	95%	5%	70%	30%
2024	71%	29%	48%	52%	94%	6%	76%	24%
2025	69%	31%	49%	51%	93%	7%	81%	19%

2026	67%	33%	40%	60%	92%	8%	40%	60%
2027	65%	35%	40%	60%	91%	9%	40%	60%
2028	64%	36%	40%	60%	90%	10%	40%	60%
2029	63%	37%	40%	60%	90%	10%	40%	60%
2030	62%	38%	40%	60%	89%	11%	40%	60%
2031	61%	39%	38%	62%	89%	11%	N/A	N/A
2032	60%	40%	40%	60%	89%	11%	N/A	N/A
2033	59%	41%	40%	60%	89%	11%	N/A	N/A
2034	58%	42%	40%	60%	89%	11%	N/A	N/A
2035	58%	42%	40%	60%	89%	11%	N/A	N/A

For the purposes of calculating DEC's and DEP's reserve margins, both Companies assumed a 50/50 blend of FT and SAT solar on their systems. This same assumption was used in the capacity expansion model for attributing capacity value to new standalone solar additions in DEC. While that assumption holds through 2025, after 2025, incremental solar transitions to a 60/40 blend. However, adjusting the model to account for this slight change would have only increased the winter capacity value for new solar by no more than 0.2%.

Q. WHAT WAS THE RESULTING ASSUMPTION FOR CONTRIBUTION TO WINTER PEAK DEMAND FOR SOLAR?

A. As shown in the Figures 17 and 18 below, the assumption for solar contribution to winter peak demand in both DEC and DEP was approximately 1% of nameplate capacity

Kalemba Rebuttal Figure 17: Calculation of Winter Contribution to Peak for Standalone Solar in DEP

	Incremental MWs	Cumulative MWs	Fixed	Tracking	FT Winter Cap Credit	SAT Winter Cap Credit	Blend Winter Cap Credit
0 Solar		1			1.2%		
Increment 1	2950	2950			0.6%		**0.7%**
Increment 2	160	3110	50%	50%	0.3%	3.2%	**1.7%**
Increment 3	180	3290	50%	50%	0.3%	3.1%	**1.7%**
Increment 4	160	3450	50%	50%	0.2%	2.8%	**1.5%**

Increment 5	135	3585	50%	50%	0.2%	2.7%	**1.5%**

Kalemba Rebuttal Figure 18: Calculation of Winter Contribution to Peak for Standalone Solar in DEC

	Incremental MWs	Cumulative MWs	Fixed	Tracking	FT Winter Cap Credit	SAT Winter Cap Credit	Blend Winter Cap Credit
0 Solar	1	1			2.50%		
Increment 1	840	840			0.9%		**0.9%**
Increment 2	680	1520	50%	50%	0.5%	2.0%	**1.2%**
Increment 3	780	2300	50%	50%	0.4%	1.8%	**1.1%**
Increment 4	780	3080	50%	50%	0.2%	1.3%	**0.7%**
Increment 5	420	3500	50%	50%	0.2%	1.1%	**0.7%**

Q. DO YOU BELIEVE THESE ASSUMPTIONS ARE REASONABLE?

A. Yes, based on the information that was available at the time and the results of the 2018 Solar Capacity Value Study, I believe these assumptions are reasonable for long-term planning purposes.

Q. WITNESS LUCAS TAKES ISSUE WITH THE INTERCONNECTION LIMITS INCLUDED IN THE MODEL. WHY IS AN INTERCONNECTION LIMIT APPROPRIATE?

A. It is important to understand that due to timing and physical constraints, there is a limitation on the amount of new generation that can be interconnected to the Companies' systems each year. The process through which new requests to interconnect to the Companies' systems and the studies that evaluate the potential interconnection are time consuming and complex. The complexity and time required only increases as more generation is added to the distribution and transmission systems. Today, significant portions of the DEC and DEP systems are identified as "constrained" meaning that significant transmission upgrades are required in order to add additional generation. Once the interconnection study process is complete, the construction of the network upgrades is dependent on a number of factors, including: other work taking place on the transmission system (i.e. customer connections, maintenance, other interconnection construction and general transmission projects), generator outages which can change power flows on the system, and projected energy demand on the system. Generally, over the course of the year there are only about 24 weeks (during the shoulder months) where transmission outages take place.

Q. WHY IS IT APPROPRIATE TO INCLUDE A 500 MW INTERCONNECTION LIMIT IF DEC AND DEP HAVE INTERCONNECTED MORE THAN 500 MW IN PRIOR YEARS?

A. As described in Witness Lucas's Exhibit KL-12, the average number of megawatts interconnected each year from 2014-2019 was 527 MW. While the Companies did interconnect 744 MW in 2017, only 556 MW were interconnected in 2018 and 267 MW were interconnected in 2019. Given the saturation of solar on the DEC and DEP systems, maintaining the pace of interconnecting new solar at the rate of the 2017 time period will be challenging. This is evidenced further by the fact that the Companies interconnected only 320 MW in 2020.

Finally, while not an issue through 2030, the same resources that are required for interconnecting this solar generation would also be needed for interconnecting up to 300 MW/year of onshore Carolinas wind between DEC and DEP in the later portion of the planning horizon.

Q. WILL THE COMPANIES' QUEUE REFORM EFFORTS IMPROVE THIS?

A. The Companies' "queue reform" effort, which was recently approved by the Commission and the North Carolina Utilities Commission, will allow for "cluster studies" of groups of projects seeking interconnection to the Companies' system. These changes to the manner in which proposed generators are studied should improve the efficiency of transmission impact studies by eliminating the sequential method that projects are currently studied under and spreading the costs of larger upgrades across projects. However, that will not change the fact that larger projects can lead to more complex interconnection solutions on the system with more network upgrades required; and, as smaller projects have been sited closer to existing transmission infrastructure, future projects will be sited further from that infrastructure potentially requiring more time consuming right-of-way acquisition and more complex projects just to reach the existing transmission infrastructure.

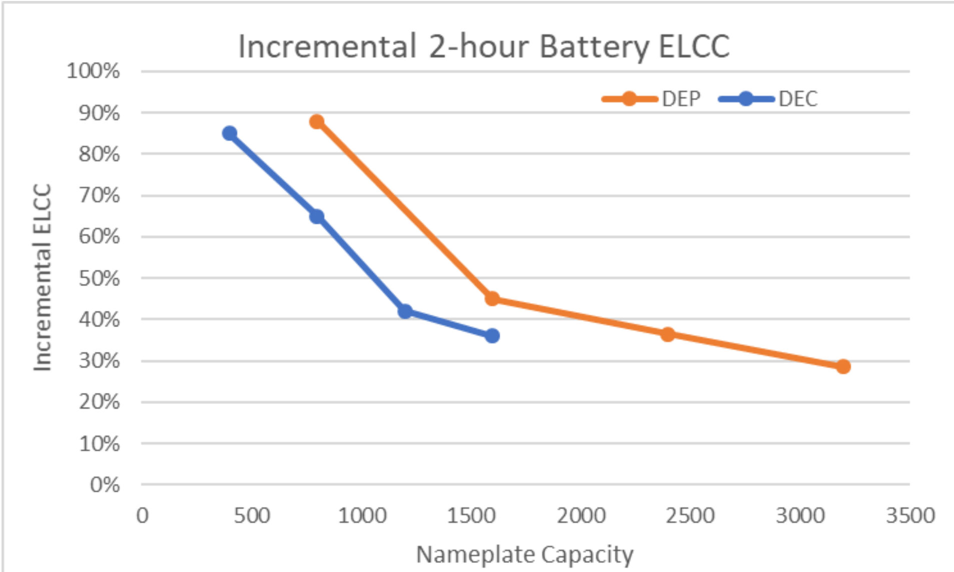
VI: <u>2020 STORAGE ELCC STUDY</u>

Q. WITNESS LUCAS RECOMMENDS THAT THE COMPANIES UPDATE THE MODEL TO SELECT UP TO 1,500 MW OF TWO-HOUR BATTERIES IN DEP AND UP TO 1,000 MW OF TWO-HOUR BATTERIES IN DEC.[33] DO YOU THINK THIS IS REASONABLE?

A. This is not reasonable. While it is true that the Storage ELCC Study did identify that 2-hour battery storage could potentially provide nearly 90% capacity value for the first increments of storage, that value quickly drops as incremental storage is added as evidenced in the Figure 19 below.

[33] *Id.* at 47.

Kalemba Rebuttal Figure 19: Incremental 2-hour Battery Storage ELCC



Additionally, Witness Lucas relies on Figure 6 in his testimony which represents the *average* value of 2-hour storage on the DEP and DEC systems, but the *incremental* 2-hour battery ELCC is necessary for evaluating the value of incremental 2-hour battery additions to the system.

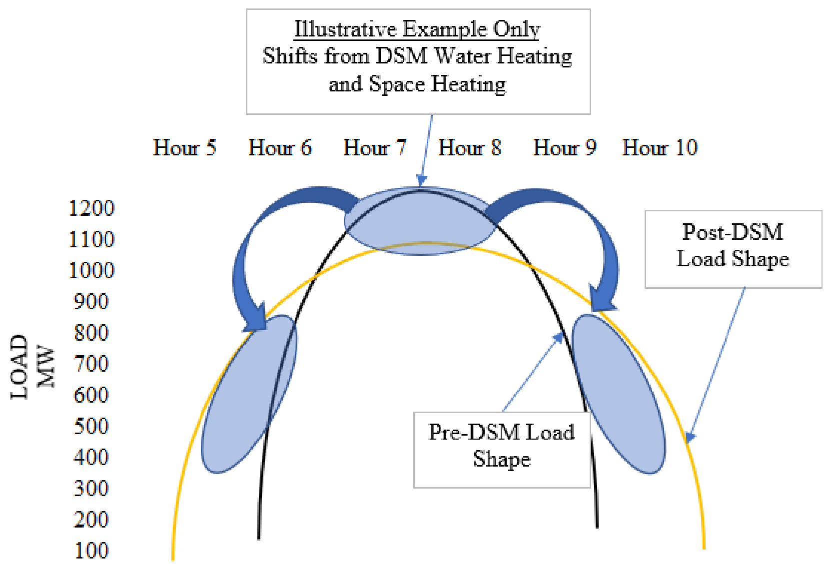
Q. TO FURTHER HIS ARGUMENT FOR INCLUDING 2-HOUR STORAGE WITNESS LUCAS STATES "DSM PROGRAMS TYPICALLY HAVE LIMITS ON HOW OFTEN THEY CAN BE ACTIVATED, AND EVEN IF THEY DID NOT, PARTICIPANT FATIGUE COULD DIMINISH THE RESPONSE AFTER MULTIPLE CONSECUTIVE CALLS."[34] IS THIS A VALID ARGUMENT?

A. While it is true that some DSM programs have limits to how often they can be activated, and participant fatigue is a valid concern, DSM programs receive 100% contribution to winter peak capacity in the IRP. While DEC/DEP Witness Snider points out in his

[34] *Id.* at 46.

testimony that the additional DSM identified in the Companies' Winter Peak Assessment is not fully available until 2041, any additional demand response programs, as shown in Figure 20, will have the impact of flattening winter peak demand thereby increasing the need for longer duration resources.

Kalemba Rebuttal Figure 20: Illustrative Example of Impact of DSM Programs on Winter Peak Demand



This highlights the fact that there is only so much need on the system for narrow limited-hour load shifting resources before longer duration storage is needed.

Q. WHAT ARE THE RISKS OF TOO MUCH RELIANCE ON SHORT DURATION LOAD SHIFTING RESOURCES?

A. The risk facing the Companies and our customers from too much reliance on short duration load shifting resources is both a reliability issue and an economic issue. Several reliability events across the nation highlight the potential for longer duration peak events that require resources with sustainable output over longer durations of time. From an economic perspective if it turns out longer duration storage is required to reliably serve load then customers effectively end up paying for capacity twice as they would need to buy multiple MWs of short duration storage to equal a single MW of a reliable longer duration resource. While the Companies supports and stand behind their ELCC modeling, it should be recognized that all operational considerations cannot be fully captured in an ELCC modeling framework and the Companies are ultimately responsible for the reliable provision of electric service. Given the potential for demand side resources to satisfy the incremental demand over shorter periods of time, the Companies are only considering four-hour storage, or longer, for capacity value in their IRPs.

Q. ARE THERE RECENT EXAMPLES THAT MIGHT BE USEFUL WHEN CONSIDERING WHETHER OR NOT TO INCLUDE 2-HOUR BATTERY STORAGE IN THE IRP?

A. Yes. The recent extended extreme cold weather event in Texas on the ERCOT system is a potential example where 2-hour battery storage would have likely been of little use to the system as outages to a variety of resources limited both capacity and energy to serve customer needs. Without the energy from those resources, the availability to charge any amount of battery storage would have likely been limited.

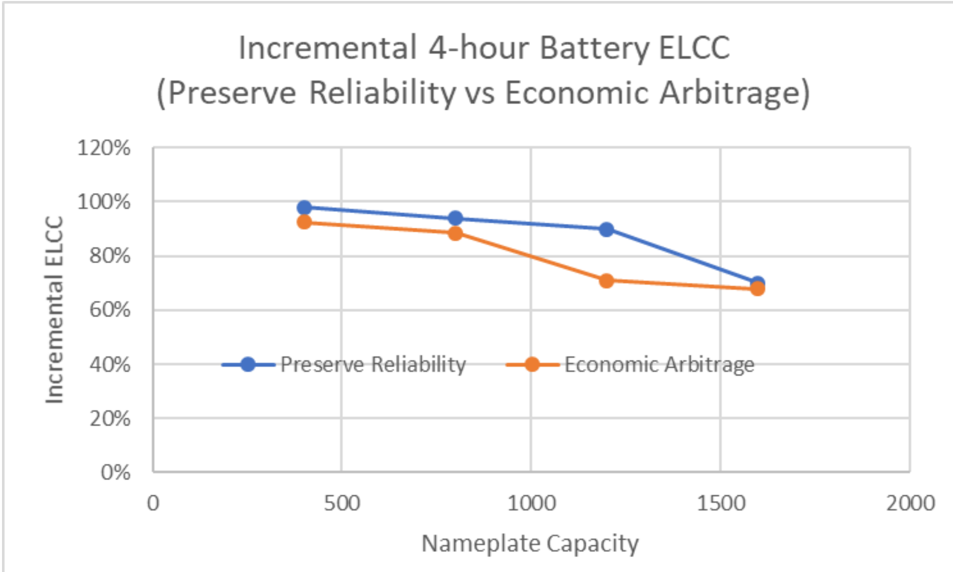
Additionally, in January 2018, the Carolinas experienced a prolonged cold weather event that fortunately did not result in the inability of the Companies to serve their customers, but the system was strained, nonetheless. The Jocassee and Bad Creek Pumped Hydro Storage resources that provide approximately 12-hours of energy were nearly exhausted during that event. It is unlikely that 2-hour storage would have provided much capacity value during that week.

Q. WITNESS OLSON STATES THAT ENERGY STORAGE RESOURCES SHOULD BE MODELED ON A "PRESERVE RELIABILITY" BASIS AS OPPOSED TO AN "ECONOMIC ARBITRAGE" BASIS.[35] WOULD THAT BE AN APPROPRIATE ASSUMPTION GIVEN THE WAY IN WHICH BATTERIES ARE EXPECTED TO BE DISPATCHED ON THE SYSTEM IN THE FUTURE?

A. No, it would not be an appropriate assumption. The economics of battery storage are not based on a single value stream. In generation space, battery storage can provide both capacity and energy arbitrage value, as well as, some support to ancillary requirements. If battery storage is going to be valuable to the DEC and DEP systems, it will need to provide all of these value streams. If the Companies were to assume energy storage capacity value based on "preserve reliability" mode, then its economic arbitrage value would be reduced. While an "economic arbitrage" basis does reduce capacity value, as shown in Figure 21, the drop off in value is initially relatively minor, 5 to 6% for the first 800 MW and the incremental value is essentially the same for the two modes at 1,600 MW of storage.

[35] CCEBA Lucas Direct, at 46.

Kalemba Rebuttal Figure 21: Comparison of "Preserve Reliability" Mode to "Economic Arbitrage" Mode in DEC



The "economic arbitrage" mode maximizes the energy value of the battery while still providing significant capacity value, and therefore the "preserve reliability" assumption in the IRP is appropriate for valuing capacity value of storage.

Q. WITNESS OLSON RAISES CONCERNS THAT THE COMPANIES DID NOT ACCOUNT FOR THE SYNERGIES BETWEEN SOLAR AND STORAGE IN THE 2020 IRPs. PLEASE EXPLAIN HOW THE COMPANIES ACCOUNTED FOR THESE SYNERGIES.

A. As DEC/DEP Witness Wintermantel explains in his testimony, Astrapé evaluated significant levels of solar on the DEC and DEP systems when performing the 2020 Storage ELCC Study. Any synergies that solar provides to storage are accounted for in that study. When the Companies evaluated storage on the DEC and DEP systems, the amount of solar on those systems was significant and already in the range of the amount solar included in the Storage ELCC Study. For that reason, the Companies attributed 90% capacity value to incremental 4-hour standalone storage in DEC and 95% capacity value to incremental 4-hour storage in DEP when evaluating the value of the first tranche of storage on the systems.

Additionally, the Companies further enabled the synergies between solar and storage by allowing the model to select solar paired with storage resources. In the Base with Carbon Policy portfolio, the model selected nearly 1,000 MW of this resource in DEC and over 1,400 MW in DEP by the end of the planning horizon.

Q. THE ORS RECOMMENDS THAT FURTHER INVESTIGATION BE CONDUCTED REGARDING THE COMPANIES' SOLAR CAPACITY VALUES AND SOLAR PLUS BATTERY ENERGY STORAGE CAPACITY VALUES WITH STAKEHOLDER INPUT, DISCUSSED AS PART OF A STAKEHOLDER ENGAGEMENT PROCESS.[36] ARE THE COMPANIES WILLING TO INCLUDE THIS AS PART OF THE NEXT STAKEHOLDER PROCESS?

A. The Companies are open to discussing the results of the ELCC studies with stakeholders during the stakeholder engagement process. As Witness Snider states in his testimony, there are a limited number of sensitivities and analyses that can take place within any IRP process. If after discussions with stakeholders, sensitivities of the impacts of higher capacity value of storage and/or solar on the resource plan is seen as a high priority, the Companies will evaluate those sensitivities.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[36] ORS Hayet Direct, at 10.